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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Application of Pacific Gas and Electric Company for Wildfire Mitigation and Catastrophic Events Interim Rates (U 39 E)	Application No. 20-02-_______

APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) FOR WILDFIRE MITIGATION AND CATASTROPHIC EVENTS INTERIM RATES

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Dated: February 7, 2020

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APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) FOR WILDFIRE MITIGATION AND CATASTROPHIC EVENTS INTERIM RATES

Pursuant to Article 2 of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission or CPUC), Public Utilities Code Sections 454 and 701, Pacific Gas and Electric Company (PG&E or the Company) submits this application to recover interim rates for costs recorded in various wildfire mitigation and catastrophic events memorandum accounts. The costs addressed in this application cover activities mainly during the years 2017-2019 and are incremental to those previously authorized in PG&E's 2017 General Rate Case (GRC) and other proceedings. The underlying costs supporting the proposed interim rates are for mandatory work to mitigate wildfire risk and respond to catastrophes.

PG&E has previously notified the Commission and interested parties that the Company was accumulating significant costs associated with wildfire mitigation and response. For instance, in PG&E's 2020 GRC, PG&E explained that it expected a balance of CPUC-jurisdictional wildfire mitigation costs of approximately $1.8 billion by the end of 2019.[1/] This application concerns these types of accumulated costs.

Through this application, PG&E requests authorization to recover, on an interim basis, $899 million in revenue over a period commencing in August 2020 and continuing through

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1/ Application 18-12-009 (2020 GRC) Exhibit PG&E-15, p. 2-18.

2021. This revenue requirement is calculated as 85 percent of the revenue requirement associated with the costs PG&E has already incurred through December 31, 2019, mainly since 2017, in various wildfire- and catastrophe-related memorandum accounts.

PG&E will separately present the underlying costs addressed in this interim rate request to the Commission in one or more dockets later this year. PG&E's presentation will provide the requisite detail to show the reasonableness of these costs. Due to the time required to prepare – and for the Commission to process – such application(s), formal cost recovery may not otherwise occur for two years or more. Absent interim rates, this length of time and the magnitude of the costs involved will continue to adversely affect PG&E's cost of borrowing and its credit metrics to the detriment of customers and suppliers.[2/] Importantly, customers will not be harmed by this request for interim rates. Should one or more future Commission decisions decide that PG&E is not entitled to all the costs awarded here on an interim basis, PG&E will return any overcollection of costs to customers with interest.

This application also requests the Commission to consider a policy determination -- on a going-forward basis -- to provide interim rates, subject to refund, for significant accumulated balances in similarly-situated memorandum accounts. Specifically, PG&E seeks Commission support for interim rates whenever PG&E accumulates a total of $100 million or more (in revenue requirement equivalent) relating to new Commission- or legislative-mandated activity in one or more memorandum accounts established to allow the utility to record such costs. In such circumstances, PG&E would seek to collect, in interim rates, 85% of the revenue requirement corresponding to such mandates. That is, capital and expense amounts for eligible activities would be converted to a revenue requirement, and if that revenue requirement exceeds $100 million, the total would be reduced by 15%, and included in an upcoming rate change filing submitted to the Commission.

2/ See the accompanying Declaration of David S. Thomason in support of this application.

I. CURRENT PROGRAMS FOR INTERIM RELIEF

A. The Extraordinary Circumstances of Fire Risk in Northern California

Wildfire risk and conditions in PG&E's service area are unprecedented. Until the October 2017 North Bay Fires, wildfire risk in California was largely thought to be primarily a Southern California risk. As the Commission stated in 2012:

> [t]here is no history of catastrophic power-line fires in Northern California, and Northern California does not experience Santa Ana winds that contribute significantly to the risk of catastrophic power-line fires in Southern California.[3/]

This is no longer the case.

Under the Commission's 2018 Fire-Threat Map, PG&E's service area now contains substantially more High Fire-Threat District (HFTD) areas than exist in the service territories of the other two large investor-owned electric utilities combined. More than half of PG&E's service area is designated by the Commission as extreme or elevated-fire risk.

PG&E's infrastructure spans more than 70,000 square miles. As California continues to experience the impacts of climate change, PG&E is taking action to build a more climate resilient energy network. Significant costs associated with these activities have been recorded to the memorandum accounts addressed in this proceeding. PG&E has accumulated approximately $1.9 billion in the corresponding accounts over the past three years.[4/]

B. Wildfire Risk Has Accelerated Beyond the Speed of Traditional Ratemaking

Ratemaking in California is not yet well suited to the significantly increased risk of fire in the state. For the most part, electric revenue requirements are established in utilities' GRCs. These cases typically cover a three-year or four-year rate case period and are filed more than a year in advance of the rate case period. Utilities are thus called upon to forecast wildfire mitigation work for periods of five years or more in advance.

3/ Decision 12-01-032, *mimeo*, p. 74.

4/ The $1.9 billion is before the removal of approximately $262 million of costs related to the Wildfire OII Settlement (discussed below). After the removal of the Wildfire OII settlement related amounts, the costs are approximately $1.67 billion.

While this process generally works well for the forecasting of routine costs, it does not work well for forecasting costs that are unpredictable or irregular in nature. For this reason, the Commission has used ratemaking mechanisms outside the GRC for catastrophic events and emerging risks that are hard to forecast.[5/]

Insofar as the GRC mechanism described above was not well-suited for the emerging risk of such fires, the Commission has addressed the ratemaking gap by allowing PG&E and other affected utilities to record fire-related costs to various memorandum accounts, such as those addressed in this application. Given the number of such accounts that the Commission has established in recent years, their cumulative balances and the time required to clear them through the application process, interim rate relief is both necessary and appropriate. Moreover, interim rate relief will lower PG&E's cost of borrowing and improve its credit metrics to the benefit of customers, suppliers and PG&E as described more fully below.[6/]

C. Programs and Costs at Issue in this Application

PG&E seeks only Electric Distribution costs in this application. No other line of business costs are included in this request.

This application addresses the following accounts.

1. Fire Hazard Prevention Memorandum Account (FHPMA)

The purpose of the FHPMA is to track and record costs associated with the implementation of regulations and requirements adopted in Commission Rulemakings 08-11-005, 15-05-006, and subsequent proceedings (collectively referred to as the "Fire Safety Rulemakings").

In alignment with the Fire Safety Rulemakings, PG&E began performing the requisite enhanced vegetation management work in Tier 2 (elevated risk) and Tier 3 (extreme risk)

5/ Typically, costs are tracked to memorandum accounts for separate cost recovery, producing a regulatory lag for cost recovery due to the length of time required to prepare the requisite application and seek regulatory review.

6/ See the Declaration of David S. Thomason in support of this application.

HFTDs in order to prevent wildfires and ensure public safety in the designated HFTDs. The enhanced vegetation management work included: clearing branches overhanging or within four feet of powerlines, removing trees that have the potential to strike powerlines and reducing fuel near powerlines.

2. Fire Risk Mitigation Memorandum Account (FRMMA)/ Wildfire Mitigation Plan Memorandum Account (WMPMA)

FRMMA: The purpose of the FRMMA is to record, pursuant to Senate Bill (SB) 901,[7/] incremental costs of fire risk mitigation work that is not otherwise recovered in PG&E's adopted revenue requirements. Such costs include expense and capital expenditures for: advanced system hardening and resiliency; expanded automation and protection; improved wildfire detection; enhanced event response capacity; and enhanced vegetation management activities not sought under other accounts.

Costs to be recovered through the FRMMA do not include costs approved for recovery in PG&E GRCs or through other cost recovery mechanisms including the memorandum account approved as part of PG&E's annual Wildfire Mitigation Plan, as set forth in SB 901.[8/]

WMPMA: The purpose of the WMPMA is to record, pursuant to SB 901 and the Wildfire Mitigation Plan (also known as the Wildfire Safety Plan) approved by the Commission, incremental costs incurred to implement an approved wildfire mitigation plan that are not otherwise recovered in PG&E's adopted revenue requirements. Such costs may include expense and capital expenditures for activities including but not limited to: operational practices, inspection programs, system hardening, enhanced vegetation management (not sought elsewhere), enhanced situational awareness, public safety power shutoffs, and alternative technologies.

7/ Public Utilities Code Section 8386 (j), as enacted by SB 901, later amended by AB 1054 (Public Utilities Code Section 8386.4).

8/ Public Utilities Code Section 8386 (e), as enacted by SB 901, later amended by AB 1054 (Public Utilities Code Section 8386.4).

The 2019 FRMMA and WMPMA costs relate to weather stations, high definition cameras, enhanced vegetation management, adding remote control capability to all operational line reclosers in HFTDs,[9] and system hardening.

3. Catastrophic Event Memorandum Account (CEMA)

The purpose of the CEMA is to record costs for "(1) restoring utility services to customers, (2) repairing, replacing, or restoring damaged utility facilities and (3) complying with governmental agency orders in connection with events declared disasters by competent state or federal authorities."[10] Five CEMA-eligible events from 2019 are included in this request. The five activities are: (i) the January/February Severe Storms, (ii) the October Wind Events, (iii) the Glencove Fire, (iv) the Camino Fire and (v) tree mortality and fire risk reduction activities conducted pursuant to Commission Resolution ESRB-4.[11]

The types of costs recorded to CEMA for the events listed above are consistent with those sought in PG&E's prior CEMA applications. For Electric Distribution emergency response work, the costs incurred were necessary to eliminate potentially hazardous conditions, communicate with customers, repair or replace damaged facilities and restore vital services. For the tree mortality and fire risk reduction costs, PG&E undertook proactive measures to reduce the likelihood of fires started by or threatening utility facilities by identifying and removing dead and dying trees, managing vegetation, and taking related measures to increase customer safety and protect PG&E assets.

D. Wildfires Order Instituting Investigation Costs Removed

In calculating the costs to be recovered in interim rates pursuant to this application,

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9/ Reclosers shorten some power outages by sending a live pulse to test the lines after a fault has been detected. During wildfire season, this functionality was turned off for safety in HFTDs.

10/ Public Utilities Code Section 454.9(a).

11/ PG&E expects to seek formal cost recovery of the 2019 tree mortality and fire risk reduction costs in its 2018 CEMA case already on file with the Commission. (A.18-03-015.)

Other costs recorded to CEMA during 2019 associated with the Kincade fire, Bethel Island Fire and the PSPS events are not included in this application.

PG&E ensured that all costs for the activities identified in and excluded from cost recovery by the pending settlement agreement in the Wildfires Order Instituting Investigation (I.19-06-015) ("Wildfire OII") were removed.[12/]

E. Amounts

The total costs recorded in the accounts relevant to this application are set forth in the table below, net of the pending Wildfire OII settlement reductions.

TABLE 1
TOTAL RECORDED AMOUNTS BY PROGRAM AND YEAR, NET OF WILDFIRE OII REDUCTIONS
(THOUSANDS OF DOLLARS)

Line		Prior to 2018		2018		2019		Total Spending
No.	**Program**	**Expense**	**Capital**	**Expense**	**Capital**	**Expense**	**Capital**	**Total**
1	FHPMA	$793	$0	$272,224	$0	$22,447	$0	$295,464
2	FRMMA / WMPMA	-	-	-	-	488,644	585,142	1,073,786
3	CEMA	-	-	-	-	202,202	99,122	301,324
4	**Total**	**$793**	**$0**	**$272,224**	**$0**	**$713,293**	**$684,264**	**$1,670,574**

The costs included in this application are as of the first financial close for December 2019[13/] for electric distribution. PG&E will adjust these figures as necessary when preparing the formal cost recovery application(s) later this year.

12/ On December 17, 2019, a Joint Motion was filed by PG&E, the Safety and Enforcement Division of the California Public Utilities, Coalition of California Utility Employees, and the Office of Safety Advocate for approval of a Settlement Agreement in Order Instituting Investigation I.19-06-015.

13/ For the financial year of 2019, PG&E closed its accounting process on January 7, 2020 to prepare preliminary financial statements and review financial costs for December 2019. The final financial close is scheduled to be completed in mid-February 2020.

Table 2 shows the total revenue requirement corresponding to the $1.671 billion calculated in Table 1.

TABLE 2
RECORDED AMOUNTS BY PROGRAM CONVERTED TO REVENUE REQUIREMENT
(THOUSANDS OF DOLLARS)

Line No.	Program	Expense	Capital	Total	Associated Revenue Requirements
1	FHPMA	295,464	-	295,464	317,441
2	FRMMA / WMPMA	488,644	585,142	1,073,786	505,250
3	CEMA	202,202	99,122	301,324	234,871
4	**Total**	**$ 986,310**	**$ 684,264**	**$ 1,670,574**	**$ 1,057,561**

II. RELIEF SOUGHT

In this application, PG&E requests authorization to recover, on an interim basis, $899 million in revenue over a period commencing in August 2020 and concluding at the end of 2021. The calculations and details supporting this request and proposal are described and shown in Section A below.

PG&E also seeks a policy determination concerning the availability of interim rates, going-forward, for similar costs. This relief is discussed in Section B. below.

A. Interim Rates for Current Programs

1. Calculation of 85 Percent of Associated Revenue Requirement

PG&E seeks to recover, on an interim basis, 85 percent of the associated revenue requirement associated with the recorded costs discussed above. A 15 percent reduction is expected to be substantially more than the typical level of adjustments to otherwise-eligible recorded costs. Such a reduction is also consistent with historical cost recovery percentages for

PG&E's recent CEMA filings.

Table 3 below shows this calculation.

TABLE 3
CALCULATION OF 85 PERCENT OF THE ASSOCIATED REVENUE REQUIREMENT
(THOUSANDS OF DOLLARS)

Line No.	Program	Total Associated Revenue Requirement	85% of Associated Revenue Requirement
1	FHPMA	317,441	269,825
2	FRMMA/WMPMA	505,250	429,462
3	CEMA	234,871	199,640
4	**Total**	**$ 1,057,561**	**$898,927**

Table 4 below provides more detail on the expense revenue requirement and capital revenue requirement breakouts to arrive at the total of $899 million.

TABLE 4
REVENUE REQUIREMENT BY PROGRAM ADJUSTED FOR WILDFIRE OII SETTLEMENT
(MILLIONS OF DOLLARS)

Line No.	Program	Expense Revenue Requirement	Capital Revenue Requirement	Total Revenue Requirement	85% of the Total Revenue Requirement
1	FHPMA	$317.4	-	$317.4	$269.8
2	FRMMA / WMPMA	513.4	(8.1)	505.3	429.5
3	CEMA	212.4	22.4	234.9	199.6
4	**Total**	**$1,043.3**	**$14.3**	**$1,057.6**	**$898.9**

2. Proposed Ratemaking

PG&E proposes to recover the interim revenue requirement of $899 million over a 17-month period, from August 2020 through the end of 2021, or as soon as practicable following a final decision. The approved revenue requirement will be included in the Distribution Revenue Adjustment Mechanism (DRAM) in an upcoming rate change filing.

The interim rates to recover these costs will be set in the same manner as rates set to recover electric distribution costs using existing methodologies for revenue allocation and rate design The change in rates for approved cost recovery in this application will affect total charges for bundled customers and for customers who purchase energy from other suppliers (i.e., direct access and community choice aggregation customers).

3. Subject to Refund

PG&E expects to seek formal recovery of the above-referenced costs later this year in one or more dockets. Should the final decision(s) in the other dockets for these costs award PG&E an amount lower than PG&E is authorized to recover on an interim basis, PG&E proposes to refund to customers any over-collections with interest at the three-month commercial paper rate.

4. Expected Bill Impact for Residential Customers

PG&E's requested interim relief would have the following expected impact on residential customer bills. A typical residential electric customer using 500 kilowatt-hours per month would see his/her monthly bill increase by approximately 5 percent, or $5.70 monthly over 17-months. There would be no increase for gas customers' bills.

B. Policy Determination

1. Requested Ruling

As mentioned above, this application also seeks a policy determination -- on a going-forward basis -- to provide interim rates, subject to refund, for significant accumulated balances in similarly-situated memorandum accounts. That is, PG&E seeks Commission authorization for interim rate relief whenever PG&E accumulates a total of $100 million or more (on a revenue requirement basis) relating to new Commission- or legislatively-mandated activities in one or more memorandum accounts that are established to record such costs.

In such circumstances, PG&E seeks authority to collect, in interim rates, 85% of the revenue requirement corresponding to such new mandates once the revenue requirement for such mandated activities exceeds $100 million. That is, once capital and expense amounts for new activities in memorandum accounts reach a threshold of $100 million or more on a revenue requirement basis, the revenue requirement amount would be reduced by 15% and included in an upcoming rate change filing. Prior to including the revenue requirement in a rate change filing, PG&E proposes to provide a Tier 1 advice letter, providing notice to the Commission and interested parties and the requisite calculations supporting the interim rates.

This policy would have several benefits. First, it would promote fairness to the utility in providing more prompt rate recovery of costs for mandated activities. Second, it would mitigate the need for potentially costly financing. Third, it would help to smooth customer rates. Fourth, it would help to promote intergenerational equity by having customers closer-in-time to the incurrence of those costs pay for such costs.

Notably, this policy determination would achieve these benefits without increasing risk to customers as any amounts collected through interim rates would be subject to refund with interest should the Commission determine that recovery was not appropriate in a subsequent reasonableness review.

2. Illustrative Example

An example will help to illustrate PG&E's proposal. For instance, assume that the Commission were to order PG&E to undertake certain new activities, with costs for those activities to be recorded to two memorandum accounts. In one account, PG&E records $80 million in expense in year one. In the other account, PG&E records nothing. In year two, PG&E records an additional $40 million expense to the first account. In year two, PG&E records $10 million expense to the second account. The total for both accounts after two years is now $130 million expense (or revenue requirement equivalent). PG&E would thus be entitled to interim relief.

Applying the 15% reduction to the $130 million total, PG&E would be authorized to include approximately $110.5 million in interim rates after noticing this occurrence through a Tier 1 advice letter and including it in a rate change filing. If the Commission later determines that PG&E should be authorized less than $110.5 million, then PG&E would refund to customers the overcollection, plus interest.

III. NEED FOR AND BENEFITS FROM RELIEF

PG&E has incurred substantial costs to perform activities related to its wildfire mitigation efforts related to the 2019 Wildfire Mitigation Plan, Fire Safety Rulemakings, and catastrophic event response. As explained above, PG&E has incurred approximately $1.9 billion in unreimbursed costs for these applicable accounts through the end of 2019.

A. Interim Rates are Justified for Reasons of Fairness

Interim rate relief for PG&E is justified for reasons of fairness. PG&E has incurred the applicable costs not on its own discretion, but rather as a result of legislative and regulatory mandates. PG&E has incurred these costs to provide safe and reliable service, consistent with state standards, and to restore service to customers following declared disasters. PG&E should not be required to carry such significant costs prior to cost recovery. For these and other mandated tasks, PG&E deserves prompt rate recovery for its costs.

B. Benefits to Customers

Interim rate relief will benefit customers through lower rates associated with better credit quality and credit ratings. PG&E expects to file an update to its cost of debt upon emergence from bankruptcy. To the extent this interim relief lowers PG&E's cost of debt, customers would benefit as soon as this Fall by an adjustment lowering PG&E's cost of capital.

Additionally, there are likely to be longer-term customer benefits associated with an improved perception of regulatory risk and impacted credit metrics. These customer benefits would likely be realized in PG&E's next cost of capital proceeding, when such improvements would translate to reductions in the otherwise-applicable cost of capital.

C. Benefits of Interim Rates to Suppliers

PG&E's suppliers are also adversely impacted by PG&E's declining financial health. The potential for higher costs to suppliers resulting from the lack of timely cost recovery is substantial, and could be on the order of hundreds of millions of dollars in future years. As such, PG&E and the CPUC should collectively be looking for any reasonable action that can be taken to both improve credit ratings and reduce the cost of capital for our customers.

D. Equity in Ratemaking

An important principle in ratemaking is "that costs borne by ratepayers should closely match benefits they receive."[14/] The closer in time between the receipt of services and the inclusion of the resulting costs in rates, the greater the adherence to this principle. In the matter at hand, costs already incurred for customers ideally would be recovered from customers as soon as possible. Understandably, perfect alignment is not possible. Nonetheless, greater alignment is a goal to promote and achieve when practicable.

IV. LEGAL BASIS FOR APPLICATION

"The Commission's authority to grant interim rate relief is well established."[15/]

The above quotation comes from the Commission's recent decision in PG&E's CEMA case filed in March 2018. There, the Commission cited *Toward Utility Rate Normalization v. Public Utilities Commission*, (1988) 44 Cal.3d 870, which found the Commission had broad authority to authorize interim rate relief. In response to TURN's argument that interim relief should be limited to those situations of "financial emergency" and where the reasonableness of costs is "undisputed," the Supreme Court disagreed, concluding "[f]rom the existence of those two exceptions…it does not follow that no other circumstances can justify an interim increase."[16/]

14/ *Toward Utility Rate Normalization v. Public Utilities Commission*, (1988) 44 Cal.3d 870, 877.

15/ D.19-04-039, *mimeo*, p. 5 (emphasis added); see also p. 13 (Conclusion of Law 1).

16/ D.19-04-039, *mimeo*, p. 5, citing *TURN v. PUC*, (1988) 44 Cal.3d at 875.

Indeed, the Commission has granted interim rate relief in a variety of circumstances. The Commission has done so to promote fairness to both the utility and the public,[17/] to reduce the potential for rate shock,[18/] and to preserve the financial integrity of a utility, minimize costs incurred by ratepayers and ensure rate stability.[19/] The "utility's continued viability need not be on the line before interim rate relief may be granted."[20/]

The circumstances here are similar to those supporting interim relief in D.19-04-039. There, the Commission concluded:

> As the costs that PG&E seeks to recover were incurred in 2016 and 2017, some level of interim rate relief would result in improved intergenerational equity, as vegetation management costs would be allocated to ratepayers in a manner that more closely aligns with the timing of when the costs were incurred. Interim rate relief is also likely to avoid a potentially far larger rate increase on customers after the reasonableness review by this Commission that will be undertaken later in this proceeding. We are also persuaded, in light of PG&E's financial condition and the perception of that condition represented by rating agency reports, that it would be unreasonable to continue to require PG&E to wait for recovery of these amounts. In light of these circumstances, interim recovery is warranted to promote fairness, minimize costs to ratepayers, and promote rate stability.[21/]

The Commission can, and should, make a similar finding here.

Additionally, the Commission provided very similar relief to that sought here in its decision approving Sempra Energy's (Sempra) request in its Pipeline Safety Enhancement Program filing.[22/] There, Sempra proposed – and the Commission agreed – that 50% of actual spending booked to a memorandum account should flow into the following year's rates for recovery without litigation, although 100% of the total spending was subject to reasonableness in their future General Rate Case.

17/ D.02-07-031, *mimeo*, p. 14, discussed at D.19-04-039, *mimeo*, p. 6.

18/ D.16-08-003, *mimeo*, p. 9, discussed at D.19-04-039, *mimeo*, p. 6.

19/ D.88-05-074, *mimeo*, p. 14, discussed at D.19-04-039, *mimeo*, p. 6.

20/ D.19-04-039, *mimeo*, p. 6.

21/ D.19-04-039, *mimeo*, p. 6 (footnote omitted).

22/ D.16-08-003.

With respect to the policy determination PG&E requests—for interim rate relief whenever PG&E accumulates a total of $100 million or more in memorandum accounts for new mandated activities—the Commission has authorized similar relief for other mandated activities. In D.02-10-062, the Commission authorized interim rate relief based on an established trigger for procurement-related costs tracked to the ERRA balancing accounts to comply with the requirements of Public Utilities Code §454.5(d)(3).[23/] The Commission noted that doing so furthered a number of important objectives including, but not limited to, improving the ability of the utilities to meet their obligation to serve their customers' electric loads; assuring just and reasonable electricity rates; enhancing the financial stability and creditworthiness of respondent utilities; and ensuring timely recovery of procurement costs in rates.[24/] PG&E recommends that the Commission adopt PG&E's proposal here for the same reasons.

V. OVERVIEW OF DECLARATION

This application is supported by the accompanying declaration.

The declaration of David Thomason, Chief Financial Officer of Pacific Gas and Electric Company. Among other things, Mr. Thomason's declaration explains:

- PG&E has recorded approximately $1.9 billion of wildfire related work in the following memorandum accounts mainly for 2017-2019: FHPMA, FRMMA/WMPMA and CEMA;
- These costs were incurred for mandated and legislative-supported work to mitigate wildfire risks and respond to catastrophic events;
- These costs were recorded in accordance with PG&E's accounting controls and standards so that the right costs are recorded to the right accounts;
- PG&E will further scrutinize the costs recorded in these accounts prior to formal submission of these costs via one or more applications to be filed later this year;

23/ D.02-10-062, *mimeo*, p. 64.

24/ D.02-10-062, *mimeo*, pp. 52-54.

- PG&E believes that reducing recorded costs by 15 percent provides a reasonable cushion to avoid an over-collection;
- PG&E is in a position of financial stress that this interim relief is intended to address;
- Interim relief will benefit customers and suppliers by providing PG&E with access to lower cost funding.

VI. STATUTORY AND PROCEDURAL REQUIREMENTS

A. Statutory Authority

This application is made pursuant to Public Utilities Code Sections 454 and 701 and Article 2 of the Commission's Rules of Practice and Procedure.

B. Categorization, Hearings, and Issues to be Considered (Rules 2.1(c), 7.1).

1. Proposed Category

The purpose of this application is to request interim rates for costs recorded in various wildfire related memorandum accounts. PG&E proposes that this application be categorized as a rate-setting proceeding.

2. Need for Hearing

PG&E anticipates that hearings will not be required in this proceeding. This is because the reasonableness and incrementality of the various costs sought for interim recovery in this proceeding will be evaluated in one or more dockets at the Commission later this year.

3. Issues to be Considered

The principal issues presented in this application are:

- Whether PG&E's request to recover, on an interim basis subject to refund, $899 million in revenue requirement related to wildfire related costs incurred mainly during 2017 – 2019 in certain memorandum accounts should be granted;

- Whether PG&E's proposal to recover the authorized revenue requirements over a 17-month period, as soon as practicable following a final decision, should be granted; and
- Whether PG&E's proposal for interim rate relief whenever PG&E accumulates a total of $100 million or more (in revenue requirement equivalent) in one or more memorandum accounts for new mandated activities should be granted.

C. Proposed Schedule (Rule 2.1(c))

PG&E proposes the following schedule for processing this application:

Activity	**Proposed Date**
Application filed and Declaration served	February 7, 2020
Protests or Responses	March 12, 2020
Reply to Protests or Responses	March 23, 2020
Prehearing Conference	March 25, 2020
Concurrent Opening Briefs Due	April 15, 2020
Concurrent Reply Briefs Due	April 29, 2020
Proposed Decision Issued	May 25, 2020
Final Decision Issued	June 25, 2020

As mentioned previously, because the reasonableness and incrementality of the various costs sought for interim recovery in this proceeding will be evaluated in one or more applications later this year, there should be no factual disputes in the present proceeding that would require testimony or evidentiary hearings.

D. Legal Name and Principal Place of Business (Rule 2.1(a))

Applicant's legal name is Pacific Gas and Electric Company. Since October 10, 1905, PG&E has been an operating public utility corporation, organized under California law. It is engaged principally in the business of furnishing electric and gas service in northern and central California. Its mailing address for this matter is Post Office Box 7442, San Francisco, California 94120.

E. Correspondence and Communications Regarding this Application (Rule 2.1(b))

Communications regarding this application should be addressed to:

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Law Department
77 Beale Street, B30A
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F. Relevant Safety Considerations (Rule 2.1(c))

In D.16-01-017, the Commission amended Rule 2.1(c) requiring an applicant to identify all relevant safety considerations implicated by an application to which the assigned Commissioners and presiding officer could refer to during the proceeding. Insofar as this proceeding concerns past expenditures, this proceeding is not expected to have direct impacts on safety.

G. Article of Incorporation (Rule 2.2)

A certified copy of PG&E's Restated Articles of Incorporation, effective April 12, 2004, was filed with the Commission on May 3, 2004, in A.04-05-005. These Articles are incorporated herein by reference.

H. Balance Sheet and Income Statement (Rule 3.2(a)(1))

PG&E's most recent balance sheet and income statement were filed on November 22, 2019, in A.19-11-019, and are incorporated herein by reference.

I. Statement of Presently Effective Rates (Rule 3.2(a)(2))

PG&E's presently effective electric rates are attached as Exhibit A.

J. Statement of Proposed Rate Increases (Rule 3.2(a)(3))

The proposed changes in electric revenue are set forth in Exhibit B of this application.

K. Summary of Earnings (Rules 3.2(a)(5))

A summary of recorded 2018 revenues, expenses, rate bases and rate of return for PG&E's Electric and Gas Departments was filed with the Commission on April 22, 2019, in A.19-04-015 and is incorporated by reference herein.

L. Exhibit List and Statement of Readiness

Attached to this application are the following exhibits:

Exhibit A: Presently Effective Electric Rates

Exhibit B: Proposed Changes in Electric Revenue

Exhibit C: Affected Governmental Entities/List of Cities and Counties

Exhibit D: Declaration of David S. Thomason in Support of the Application of Pacific Gas and Electric Company for Wildfire Mitigation and Catastrophic Events Interim Rates

PG&E is ready to proceed with this case based on the facts and data contained in Exhibit D, the declaration of David S. Thomason in support of the request set forth in this application.

M. Most Recent Proxy Statement (Rule 3.2(a)(8))

PG&E's most recent proxy statement, dated May 17, 2019, was filed with the Commission on June 3, 2019, in A.19-06-001, and is incorporated herein by reference.

N. Type of Rate Change Requested (Rule 3.2(a)(10))

The rate change sought in this application establishes interim rates to recover 85 percent of the balances in certain memorandum accounts as enumerated above.

O. Service and Notice of Application (Rule 3.2(b-d))

A list of the cities and counties affected by the rate changes resulting from this application is attached as Exhibit C. The State of California is also a customer of PG&E whose rates would be affected by the proposed revisions. As provided in Rule 3.2(b), a notice describing in general terms the proposed revenue increases and rate changes will be mailed to the officials identified in Exhibit C within 20 days after the filing of this application. The notice will state that a copy of this application and related attachments would be furnished by PG&E upon written request.

Within 20 days after the filing of this application, PG&E will publish a notice of the proposed increases in rates in a newspaper of general circulation in each county in its service territory. That notice will state that a copy of this application and related attachments may be examined at the Commission's offices and such offices of PG&E as specified in the notice. A similar notice will be included in the regular bills mailed to PG&E's customers within 45 days of today's filing date.

PG&E is contemporaneously serving this application, as well as the accompanying declaration(s), on the service lists established for PG&E's 2018 CEMA Application (A.18-03-015), PG&E's 2019 CEMA Application (A.19-09-012), and PG&E's 2020 GRC Application (A.18-12-009).

VII. CONCLUSION

WHEREFORE, PG&E respectfully requests that the Commission issue a final decision:

1. Approving PG&E's request to recover, on an interim basis subject to refund, $899 million in revenue requirement related to wildfire related costs incurred mainly during 2017 - 2019 in certain memorandum accounts;

2. Adopting PG&E's proposal to recover the authorized revenue requirements over a 17-month period, as soon as practicable following a final decision;

3. Adopting PG&E's proposal for interim rate relief whenever PG&E accumulates a total of $100 million or more (in revenue requirement equivalent) in one or more memorandum accounts for new mandated activities; and

4. Granting such other and further relief as the Commission deems appropriate.

Respectfully Submitted,

STEVEN W. FRANK

By: */s/ Steven W. Frank*
STEVEN W. FRANK

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San Francisco, CA 94105
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Facsimile: (415) 973-5520
E-Mail: steven.frank@pge.com

Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: February 7, 2020

VERIFICATION

I, undersigned, say:

I am an officer of PACIFIC GAS AND ELECTRIC COMPANY, a corporation, and am authorized to make this verification for that reason.

I have read the foregoing "*Application of Pacific Gas and Electric Company for Wildfire Mitigation and Catastrophic Events Interim Rates*" and I am informed and believe the matters therein are true and on that ground I allege that the matters stated therein are true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed at San Francisco, California this 7th day of February 2020.

/s/ David S. Thomason
DAVID S. THOMASON
Chief Financial Officer

EXHIBIT A

Presently Effective Electric Rates

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Wednesday, January 01, 2020

RESIDENTIAL RATES

LINE NO.		1/1/20 RATES SUMMER	1/1/20 RATES WINTER	LINE NO.
1	SCHEDULE E-1			1
2	MINIMUM BILL ($/MONTH)	$10.00	$10.00	2
3	ES UNIT DISCOUNT ($/UNIT/MONTH)	$0.95	$0.95	3
4	ET UNIT DISCOUNT ($/UNIT/MONTH)	$1.88	$1.88	4
5	ES/ET MINIMUM RATE LIMITER ($/KWH)	$0.04892	$0.04892	5
6	ENERGY ($/KWH)			6
7	TIER 1 (Baseline Quantity - BQ)	$0.23581	$0.23581	7
8	TIER 2 > 100% of BQ	$0.29675	$0.29675	8
10	High User Surcharge (HUS) > 400% of BQ	$0.51990	$0.51990	9
12	SCHEDULE EL-1 (CARE)			10
13	MINIMUM BILL ($/MONTH)	$5.00	$5.00	11
14	ENERGY ($/KWH)			12
15	TIER 1 (Baseline Quantity - BQ)	$0.15103	$0.15103	13
16	TIER 2 > 100% of BQ	$0.18982	$0.18982	14
17	High User Surcharge (HUS) > 400% of BQ	$0.33256	$0.33256	15

Exhibit A

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Wednesday, January 01, 2020

RESIDENTIAL RATES

LINE NO.		1/1/20 RATES SUMMER	1/1/20 RATES WINTER	LINE NO.
1	SCHEDULE E-6 / EM-TOU			1
2	MINIMUM BILL ($/MONTH)	$10.00	$10.00	2
3	E-6 METER CHARGE ($/MONTH)	$7.70	$7.70	3
4	ON-PEAK ENERGY ($/KWH)			4
5	TIER 1 (Baseline Quantity - BQ)	$0.39696		5
6	TIER 2 > 100% of BQ	$0.48235		6
7	PART-PEAK ENERGY ($/KWH)			7
8	TIER 1 (Baseline Quantity - BQ)	$0.27853	$0.22447	8
9	TIER 2 > 100% of BQ	$0.36392	$0.30986	9
10	OFF-PEAK ENERGY ($/KWH)			10
11	TIER 1 (Baseline Quantity - BQ)	$0.20330	$0.20764	11
12	TIER 2 > 100% of BQ	$0.28869	$0.29303	12
13	SCHEDULE EL-6 / EML-TOU			13
14	MINIMUM BILL ($/MONTH)	$5.00	$5.00	14
15	EL-6 METER CHARGE($/MONTH)	$6.16	$6.16	15
16	ON-PEAK ENERGY ($/KWH)			16
17	TIER 1 (Baseline Quantity - BQ)	$0.25425		17
18	TIER 2 > 100% of BQ	$0.30757		18
19	PART-PEAK ENERGY ($/KWH)			19
20	TIER 1 (Baseline Quantity - BQ)	$0.17840	$0.14377	20
21	TIER 2 > 100% of BQ	$0.23172	$0.19709	21
22	OFF-PEAK ENERGY ($/KWH)			22
23	TIER 1 (Baseline Quantity - BQ)	$0.13021	$0.13299	23
24	TIER 2 > 100% of BQ	$0.18353	$0.18631	24

RESIDENTIAL RATES

LINE NO.		1/1/20 RATES SUMMER	1/1/20 RATES WINTER	LINE NO.

Exhibit A

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Wednesday, January 01, 2020

1	SCHEDULE EV: RATE A			1
2	MINIMUM BILL ($/MONTH)	$10.00	$10.00	2
3	ON-PEAK ENERGY ($/KWH)	$0.54121	$0.37957	3
4	PART-PEAK ENERGY ($/KWH)	$0.29567	$0.23289	4
5	OFF-PEAK ENERGY ($/KWH)	$0.14232	$0.14567	5
	**			
6	SCHEDULE EV: RATE B			6
7	EV-B METER CHARGE ($/MONTH)	$1.50	$1.50	7
8	ON-PEAK ENERGY ($/KWH)	$0.53525	$0.37322	8
9	PART-PEAK ENERGY ($/KWH)	$0.29269	$0.22971	9
10	OFF-PEAK ENERGY ($/KWH)	$0.14189	$0.14521	10
	**			

SMALL L&P RATES

LINE NO.		1/1/20 RATES SUMMER	1/1/20 RATES WINTER	LINE NO.
	**			
1	SCHEDULE A-1			1
2	CUSTOMER CHARGE: SINGLE-PHASE ($/MO.)	$10.00	$10.00	2
3	CUSTOMER CHARGE: POLYPHASE ($/MO.)	$25.00	$25.00	3
4	ENERGY ($/KWH)	$0.27525	$0.21471	4
	**			
5	SCHEDULE A-1 TOU			5
6	CUSTOMER CHARGE: SINGLE-PHASE ($/MO.)	$10.00	$10.00	6
7	CUSTOMER CHARGE: POLYPHASE ($/MO.)	$25.00	$25.00	7
8	ENERGY ($/KWH)			8
9	ON-PEAK	$0.28988		9
10	PART-PEAK	$0.26623	$0.24562	10
11	OFF-PEAK ENERGY	$0.23887	$0.22471	11
	**			

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Wednesday, January 01, 2020

12	SCHEDULE A-6			12
13	CUSTOMER CHARGE: SINGLE-PHASE ($/MO.)	$10.00	$10.00	13
14	CUSTOMER CHARGE: POLYPHASE ($/MO.)	$25.00	$25.00	14
15	METER CHARGE ($/MONTH)	$6.12	$6.12	15
16	METER CHARGE - RATE W ($/MONTH)	$1.80	$1.80	16
17	METER CHARGE - RATE X ($/MONTH)	$6.12	$6.12	17
18	ENERGY ($/KWH)			18
19	ON-PEAK	$0.59002		19
20	PART-PEAK	$0.29319	$0.23666	20
21	OFF-PEAK ENERGY	$0.22161	$0.21842	21

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22	SCHEDULE A-15			22
23	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	23
24	FACILITY CHARGE ($/MONTH)	$25.00	$25.00	24
25	ENERGY ($/KWH)	$0.27525	$0.21471	25

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26	SCHEDULE TC-1			26
27	CUSTOMER CHARGE ($/MONTH)	$15.00	$15.00	27
28	ENERGY ($/KWH)	$0.19293	$0.19293	28

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MEDIUM L&P RATES

LINE NO.		1/1/20 RATES SUMMER	1/1/20 RATES WINTER	LINE NO.
1	SCHEDULE A-10			1
2	CUSTOMER CHARGE ($/MONTH)	$140.00	$140.00	2
3	MAXIMUM DEMAND CHARGE ($/KW/MO)			3
4	SECONDARY VOLTAGE	$21.63	$13.11	4
5	PRIMARY VOLTAGE	$20.42	$13.34	5
6	TRANSMISSION VOLTAGE	$14.30	$10.34	6
7	ENERGY CHARGE ($/KWH)			7
8	SECONDARY VOLTAGE	$0.18115	$0.14039	8
9	PRIMARY VOLTAGE	$0.16940	$0.13562	9
10	TRANSMISSION VOLTAGE	$0.13495	$0.11418	10

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11	SCHEDULE A-10 TOU			11
12	CUSTOMER CHARGE ($/MONTH)	$140.00	$140.00	12

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Wednesday, January 01, 2020

13	MAXIMUM DEMAND CHARGE ($/KW/MO)			13
14	SECONDARY VOLTAGE	$21.63	$13.11	14
15	PRIMARY VOLTAGE	$20.42	$13.34	15
16	TRANSMISSION VOLTAGE	$14.30	$10.34	16
17	ENERGY CHARGE ($/KWH)			17
18	SECONDARY			18
19	ON PEAK	$0.23491		19
20	PARTIAL PEAK	$0.17978	$0.15039	20
21	OFF-PEAK	$0.15171	$0.13333	21
22	PRIMARY			22
23	ON PEAK	$0.22086		23
24	PARTIAL PEAK	$0.17030	$0.14657	24
25	OFF-PEAK	$0.14367	$0.13069	25
26	TRANSMISSION			26
27	ON PEAK	$0.18166		27
28	PARTIAL PEAK	$0.13479	$0.12300	28
29	OFF-PEAK	$0.10948	$0.10842	29

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E-19 FIRM RATES

LINE NO.		1/1/20 RATES SUMMER	1/1/20 RATES WINTER	LINE NO.
1	SCHEDULE E-19 T FIRM			1
2	CUSTOMER CHARGE > 500 KW ($/MONTH)	$1,400.00	$1,400.00	2
3	CUSTOMER CHARGE < 500 KW ($/MONTH)	$1,400.00	$1,400.00	3
4	TOU METER CHARGE - RATES V & X ($/MONTH)	$140.00	$140.00	4
5	TOU METER CHARGE - RATE W ($/MONTH)	$140.00	$140.00	5
6	DEMAND CHARGE ($/KW/MONTH)			6
7	ON-PEAK	$14.56		7
8	PARTIAL PEAK	$3.65	$0.00	8
9	MAXIMUM	$11.98	$11.98	9
10	ENERGY CHARGE ($/KWH)			10
11	ON-PEAK	$0.11651		11
12	PARTIAL-PEAK	$0.10173	$0.10406	12
13	OFF-PEAK	$0.08219	$0.08904	13

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14	SCHEDULE E-19 P FIRM			14
15	CUSTOMER CHARGE > 500 KW ($/MONTH)	$1,100.00	$1,100.00	15
16	CUSTOMER CHARGE < 500 KW ($/MONTH)	$1,100.00	$1,100.00	16

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Wednesday, January 01, 2020

17	TOU METER CHARGE - RATES V & X ($/MONTH)	$140.00	$140.00	17
18	TOU METER CHARGE - RATE W ($/MONTH)	$140.00	$140.00	18
19	DEMAND CHARGE ($/KW/MONTH)			19
20	ON-PEAK	$19.26		20
21	PARTIAL PEAK	$5.24	$0.17	21
22	MAXIMUM	$17.09	$17.09	22
23	ENERGY CHARGE ($/KWH)			23
24	ON-PEAK	$0.15886		24
25	PARTIAL-PEAK	$0.11385	$0.10777	25
26	OFF-PEAK	$0.08491	$0.09206	26

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27	SCHEDULE E-19 S FIRM			27
28	CUSTOMER CHARGE > 500 KW ($/MONTH)	$720.00	$720.00	28
29	CUSTOMER CHARGE < 500 KW ($/MONTH)	$720.00	$720.00	29
30	TOU METER CHARGE - RATES V & X ($/MONTH)	$140.00	$140.00	30
31	TOU METER CHARGE - RATE W ($/MONTH)	$140.00	$140.00	31
32	DEMAND CHARGE ($/KW/MONTH)			32
33	ON-PEAK	$21.62		33
34	PARTIAL PEAK	$5.99	$0.14	34
35	MAXIMUM	$20.55	$20.55	35
36	ENERGY CHARGE ($/KWH)			36
37	ON-PEAK	$0.17088		37
38	PARTIAL-PEAK	$0.12317	$0.11664	38
39	OFF-PEAK	$0.09158	$0.09942	39

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E-20 FIRM RATES

LINE NO.		1/1/20 RATES SUMMER	1/1/20 RATES WINTER	LINE NO.
1	SCHEDULE E-20 T FIRM			1
2	CUSTOMER CHARGE ($/MONTH)-FIRM	$1,500.00	$1,500.00	2
3	DEMAND CHARGE ($/KW/MONTH)			3
4	ON-PEAK	$18.84		4
5	PARTIAL PEAK	$4.49	$0.00	5
6	MAXIMUM	$10.65	$10.65	6
7	ENERGY CHARGE ($/KWH)			7
8	ON-PEAK	$0.11293		8
9	PARTIAL-PEAK	$0.09842	$0.10070	9
10	OFF-PEAK	$0.07923	$0.08596	10

Exhibit A

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Wednesday, January 01, 2020

11	SCHEDULE E-20 P FIRM			11
12	CUSTOMER CHARGE ($/MONTH)	$1,300.00	$1,300.00	12
13	DEMAND CHARGE ($/KW/MONTH)			13
14	ON-PEAK	$22.42		14
15	PARTIAL PEAK	$5.95	$0.14	15
16	MAXIMUM	$18.32	$18.32	16
17	ENERGY CHARGE ($/KWH)			17
18	ON-PEAK	$0.16214		18
19	PARTIAL-PEAK	$0.11435	$0.10805	19
20	OFF-PEAK	$0.08495	$0.09217	20
21	SCHEDULE E-20 S FIRM			21
22	CUSTOMER CHARGE ($/MONTH)	$1,300.00	$1,300.00	22
23	DEMAND CHARGE ($/KW/MONTH)			23
24	ON-PEAK	$20.85		24
25	PARTIAL PEAK	$5.76	$0.06	25
26	MAXIMUM	$20.69	$20.69	26
27	ENERGY CHARGE ($/KWH)			27
28	ON-PEAK	$0.16010		28
29	PARTIAL-PEAK	$0.11667	$0.11035	29
30	OFF-PEAK	$0.08684	$0.09420	30

OIL AND GAS EXTRACTION RATES

LINE NO.		1/1/20 RATES SUMMER	1/1/20 RATES WINTER	LINE NO.
1	SCHEDULE E-37			1
2	CUSTOMER CHARGE ($/MONTH)	$36.36	$36.36	2
3	TOU METER CHARGE - RATE W ($/MONTH)	$1.20	$1.20	3
4	TOU METER CHARGE - RATE X ($/MONTH)	$6.00	$6.00	4
5	ON PEAK DEMAND CHARGE ($/KW/MO)	$11.44		5
6	MAXIMUM DEMAND CHARGE ($/KW/MO)			6
7	SECONDARY VOLTAGE	$17.75	$6.83	7
8	PRIMARY VOLTAGE DISCOUNT	$2.01	$0.21	8
9	TRANSMISSION VOLTAGE DISCOUNT	$13.25	$5.87	9
10	ENERGY ($/KWH)			10

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Wednesday, January 01, 2020

11	ON-PEAK	$0.23498		11
12	PART-PEAK		$0.12578	12
13	OFF-PEAK	$0.10334	$0.09406	13

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STANDBY RATES

LINE NO.		1/1/20 RATES SUMMER	1/1/20 RATES WINTER	LINE NO.
1	SCHEDULE S - TRANSMISSION			1
2	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$1.87	$1.87	2
3	EFFECTIVE RESERVATION CHARGE ($/KW/MO.)	$1.59	$1.59	3
4	ENERGY ($/KWH)			4
5	ON-PEAK	$0.14854		5
6	PART-PEAK	$0.13281	$0.13529	6
7	OFF-PEAK	$0.11200	$0.11930	7
8	SCHEDULE S - PRIMARY			8
9	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$7.92	$7.92	9
10	EFFECTIVE RESERVATION CHARGE ($/KW/MO.)	$6.73	$6.73	10
11	ENERGY ($/KWH)			11
12	ON-PEAK	$0.62476		12
13	PART-PEAK	$0.29586	$0.16163	13
14	OFF-PEAK	$0.12830	$0.13697	14
15	SCHEDULE S - SECONDARY			15
16	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$7.92	$7.92	16
17	EFFECTIVE RESERVATION CHARGE ($/KW/MO.)	$6.73	$6.73	17
18	ENERGY ($/KWH)			18
19	ON-PEAK	$0.62396		19
20	PART-PEAK	$0.29506	$0.16083	20
21	OFF-PEAK	$0.12750	$0.13617	21

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Exhibit A

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Wednesday, January 01, 2020

STANDBY RATES

LINE NO.		1/1/20 RATES SUMMER	1/1/20 RATES WINTER	LINE NO.
1	SCHEDULE S CUSTOMER AND METER CHARGES			1
2	RESIDENTIAL			2
3	CUSTOMER CHARGE ($/MO)	$5.00	$5.00	3
4	TOU METER CHARGE ($/MO)	$3.90	$3.90	4
5	AGRICULTURAL			5
6	CUSTOMER CHARGE ($/MO)	$27.60	$27.60	6
7	TOU METER CHARGE ($/MO)	$6.00	$6.00	7
8	SMALL LIGHT AND POWER (less than or equal to 50 kW)			8
9	SINGLE PHASE CUSTOMER CHARGE ($/MO)	$10.00	$10.00	9
10	POLY PHASE CUSTOMER CHARGE ($/MO)	$25.00	$25.00	10
11	METER CHARGE ($/MO)	$6.12	$6.12	11
12	MEDIUM LIGHT AND POWER (>50 kW, <500 kW)			12
13	CUSTOMER CHARGE ($/MO)	$140.00	$140.00	13
14	METER CHARGE ($/MO)	$5.40	$5.40	14
15	MEDIUM LIGHT AND POWER (>500kW)			15
16	TRANSMISSION CUSTOMER CHARGE ($/MO)	$1,400.00	$1,400.00	16
17	PRIMARY CUSTOMER CHARGE ($/MO)	$1,100.00	$1,100.00	17
18	SECONDARY CUSTOMER CHARGE ($/MO)	$720.00	$720.00	18
19	LARGE LIGHT AND POWER (> 1000 kW)			19
20	TRANSMISSION CUSTOMER CHARGE ($/MO)	$1,500.00	$1,500.00	20
21	PRIMARY CUSTOMER CHARGE ($/MO)	$1,300.00	$1,300.00	21
22	SECONDARY CUSTOMER CHARGE ($/MO)	$1,300.00	$1,300.00	22
23	REDUCED CUSTOMER CHARGES ($/MO)			23
24	SMALL LIGHT AND PWR (< 50 kW)	$10.00	$10.00	24
25	MED LIGHT AND PWR (Res Capacity >75 kW and <500 kW) S	$37.57	$37.57	25
26	MED LIGHT AND PWR (Res Capacity > 500 kW and < 1000 kW) S	$240.93	$240.93	26

AGRICULTURAL RATES

LINE NO.		1/1/20 RATES SUMMER	1/1/20 RATES WINTER	LINE NO.
1	SCHEDULE AG-1A			1

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Wednesday, January 01, 2020

2	CUSTOMER CHARGE ($/MONTH)	$17.47	$17.47	2
3	CONNECTED LOAD CHARGE ($/KW/MONTH)	$9.07	$1.73	3
4	ENERGY CHARGE ($/KWH)	$0.31164	$0.24126	4
	**			
5	SCHEDULE AG-RA			5
6	CUSTOMER CHARGE - RATES A & D ($/MONTH)	$17.47	$17.47	6
7	METER CHARGE - RATE A ($/MONTH)	$6.80	$6.80	7
8	METER CHARGE - RATE D ($/MONTH)	$2.00	$2.00	8
9	CONNECTED LOAD CHARGE ($/KW/MONTH)	$8.09	$1.31	9
10	ENERGY ($/KWH)			10
11	ON-PEAK	$0.58658		11
12	PART-PEAK		$0.21147	12
13	OFF-PEAK	$0.20739	$0.17441	13
	**			
14	SCHEDULE AG-VA			14
15	CUSTOMER CHARGE - RATES A & D ($/MONTH)	$17.47	$17.47	15
16	METER CHARGE - RATE A ($/MONTH)	$6.80	$6.80	16
17	METER CHARGE - RATE D ($/MONTH)	$2.00	$2.00	17
18	CONNECTED LOAD CHARGE ($/KW/MONTH)	$8.14	$1.37	18
19	ENERGY ($/KWH)			19
20	ON-PEAK	$0.54909		20
21	PART-PEAK		$0.21329	21
22	OFF-PEAK	$0.20436	$0.17533	22
	**			
23	SCHEDULE AG-4A			23
24	CUSTOMER CHARGE - RATES A & D ($/MONTH)	$17.47	$17.47	24
25	METER CHARGE - RATE A ($/MONTH)	$6.80	$6.80	25
26	METER CHARGE - RATE D ($/MONTH)	$2.00	$2.00	26
27	CONNECTED LOAD CHARGE ($/KW/MONTH)	$9.23	$1.39	27
28	ENERGY ($/KWH)			28
29	ON-PEAK	$0.49345		29
30	PART-PEAK		$0.22648	30
31	OFF-PEAK	$0.21900	$0.18454	31
	**			
32	SCHEDULE AG-5A			32
33	CUSTOMER CHARGE - RATES A & D ($/MONTH)	$17.47	$17.47	33
34	METER CHARGE - RATE A ($/MONTH)	$6.80	$6.80	34
35	METER CHARGE - RATE D ($/MONTH)	$2.00	$2.00	35
36	CONNECTED LOAD CHARGE ($/KW/MONTH)	$13.56	$2.51	36

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Wednesday, January 01, 2020

37	ENERGY ($/KWH)			37
38	ON-PEAK	$0.34188		38
39	PART-PEAK		$0.18515	39
40	OFF-PEAK	$0.17594	$0.15703	40

AGRICULTURAL RATES

LINE NO.		1/1/20 RATES SUMMER	1/1/20 RATES WINTER	LINE NO.
1	SCHEDULE AG-1B			1
2	CUSTOMER CHARGE ($/MONTH)	$0.00	$0.00	2
3	MAXIMUM DEMAND CHARGE ($/KW/MONTH)			3
4	SECONDARY VOLTAGE	$0.00	($0.00)	4
5	PRIMARY VOLTAGE DISCOUNT	$0.00	$0.00	5
6	ENERGY CHARGE ($/KWH)	$0.29506	$0.12750	6
7	SCHEDULE AG-RB			7
8	CUSTOMER CHARGE - RATES B & E ($/MONTH)	$23.23	$23.23	8
9	METER CHARGE - RATE B ($/MONTH)	$6.00	$6.00	9
10	METER CHARGE - RATE E ($/MONTH)	$1.20	$1.20	10
11	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$4.29		11
12	MAXIMUM DEMAND CHARGE ($/KW/MONTH)			12
13	SECONDARY VOLTAGE	$11.03	$2.21	13
14	PRIMARY VOLTAGE DISCOUNT	$0.96	$0.36	14
15	ENERGY CHARGE ($/KWH)			15
16	ON-PEAK	$0.53118		16
17	PART-PEAK		$0.18478	17
18	OFF-PEAK	$0.19669	$0.15330	18
19	SCHEDULE AG-VB			19
20	CUSTOMER CHARGE - RATES B & E ($/MONTH)	$23.23	$23.23	20
21	METER CHARGE - RATE B ($/MONTH)	$6.00	$6.00	21
22	METER CHARGE - RATE E ($/MONTH)	$1.20	$1.20	22
23	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$4.30		23
24	MAXIMUM DEMAND CHARGE ($/KW/MONTH)			24
25	SECONDARY VOLTAGE	$11.14	$2.18	25
26	PRIMARY VOLTAGE DISCOUNT	$1.04	$0.34	26
27	ENERGY CHARGE ($/KWH)			27
28	ON-PEAK	$0.49504		28
29	PART-PEAK		$0.18221	29
30	OFF-PEAK	$0.19169	$0.15163	30

Exhibit A

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Wednesday, January 01, 2020

AGRICULTURAL RATES

LINE NO.		1/1/20 RATES SUMMER	1/1/20 RATES WINTER	LINE NO.
1	SCHEDULE AG-4B			1
2	CUSTOMER CHARGE - RATES B & E ($/MONTH)	$23.23	$23.23	2
3	METER CHARGE - RATE B ($/MONTH)	$6.00	$6.00	3
4	METER CHARGE - RATE E ($/MONTH)	$1.20	$1.20	4
5	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$5.98		5
6	MAXIMUM DEMAND CHARGE ($/KW/MONTH)			6
7	SECONDARY VOLTAGE	$11.26	$2.59	7
8	PRIMARY VOLTAGE DISCOUNT	$1.20	$0.40	8
9	ENERGY CHARGE ($/KWH)			9
10	ON-PEAK	$0.32481		10
11	PART-PEAK		$0.17660	11
12	OFF-PEAK	$0.17617	$0.14913	12
13	SCHEDULE AG-4C			13
14	CUSTOMER CHARGE - RATES C & F ($/MONTH)	$65.44	$65.44	14
15	METER CHARGE - RATE C ($/MONTH)	$6.00	$6.00	15
16	METER CHARGE - RATE F ($/MONTH)	$1.20	$1.20	16
17	DEMAND CHARGE ($/KW/MONTH)			17
18	ON-PEAK	$14.16		18
19	PART-PEAK	$2.70	$0.63	19
20	MAXIMUM	$5.79	$2.79	20
21	PRIMARY VOLTAGE DISCOUNT			21
22	ON-PEAK	$1.56		22
23	MAXIMUM		$0.36	23
24	TRANSMISSION VOLTAGE DISCOUNT			24
25	ON-PEAK	$7.39		25
26	PART-PEAK	$1.51	$0.63	26
27	MAXIMUM	$0.28	$1.94	27
28	ENERGY CHARGE ($/KWH)			28
29	ON-PEAK	$0.29832		29
30	PART-PEAK	$0.17563	$0.14687	30
31	OFF-PEAK	$0.13274	$0.12776	31
32	SCHEDULE AG-5B			32
33	CUSTOMER CHARGE - RATES B & E ($/MONTH)	$36.36	$36.36	33
34	METER CHARGE - RATE B ($/MONTH)	$6.00	$6.00	34
35	METER CHARGE - RATE E ($/MONTH)	$1.20	$1.20	35
36	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$11.44		36
37	MAXIMUM DEMAND CHARGE ($/KW/MONTH)			37
38	SECONDARY VOLTAGE	$17.75	$6.83	38
39	PRIMARY VOLTAGE DISCOUNT	$2.01	$0.21	39

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Wednesday, January 01, 2020

40	TRANSMISSION VOLTAGE DISCOUNT	$13.25	$5.87	40
41	ENERGY CHARGE ($/KWH)			41
42	ON-PEAK	$0.23498		42
43	PART-PEAK		$0.12578	43
44	OFF-PEAK	$0.10334	$0.09406	44

AGRICULTURAL RATES

LINE NO.		1/1/20 RATES SUMMER	1/1/20 RATES WINTER	LINE NO.
1	SCHEDULE AG-5C			1
2	CUSTOMER CHARGE - RATES C & F ($/MONTH)	$161.58	$161.58	2
3	METER CHARGE - RATE C ($/MONTH)	$6.00	$6.00	3
4	METER CHARGE - RATE F ($/MONTH)	$1.20	$1.20	4
5	DEMAND CHARGE ($/KW/MONTH)			5
6	ON-PEAK	$19.60		6
7	PART-PEAK	$4.06	$1.04	7
8	MAXIMUM	$7.02	$4.38	8
9	PRIMARY VOLTAGE DISCOUNT			9
10	ON-PEAK	$2.93		10
11	MAXIMUM		$0.29	11
12	TRANSMISSION VOLTAGE DISCOUNT			12
13	ON-PEAK	$12.15		13
14	PART-PEAK	$1.78	$1.04	14
15	MAXIMUM	$3.99	$2.87	15
16	ENERGY CHARGE ($/KWH)			16
17	ON-PEAK	$0.18259		17
18	PART-PEAK	$0.12580	$0.11099	18
19	OFF-PEAK	$0.10466	$0.10138	19
20	SCHEDULE AG-ICE			20
21	CUSTOMER CHARGE ($/MONTH)	$40.00	$40.00	21
22	METER CHARGE ($/MONTH)	$6.00	$6.00	22
23	ON-PEAK DEMAND CHARGE ($/KW/MO)	$6.95		23
24	MAXIMUM DEMAND CHARGE ($/KW/MO)			24
25	SECONDARY	$8.99	$0.00	25
26	PRIMARY	$7.85	$0.00	26
27	TRANSMISSION	$2.74	$0.00	27
28	ENERGY CHARGE ($/KWH)			28
29	ON-PEAK	$0.18414		29
30	PART-PEAK	$0.14363	$0.14731	30
31	OFF-PEAK	$0.07365	$0.07365	31

Exhibit A

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES as of
Wednesday, January 01, 2020

STREETLIGHTING RATES

LINE NO.		1/1/20 RATES SUMMER	1/1/20 RATES WINTER	LINE NO.
	**			
1	SCHEDULE LS-1			1
2	ENERGY CHARGE ($/KWH)	$0.18309	$0.18309	2
	**			
3	SCHEDULE LS-2			3
4	ENERGY CHARGE ($/KWH)	$0.18309	$0.18309	4
	**			
5	SCHEDULE LS-3			5
6	SERVICE CHARGE ($/METER/MO.)	$7.50	$7.50	6
7	ENERGY CHARGE ($/KWH)	$0.18309	$0.18309	7
	**			
8	SCHEDULE OL-1			8
9	ENERGY CHARGE ($/KWH)	$0.19008	$0.19008	9
	**			

EXHIBIT B

Proposed Changes in Electric Revenue

Table 1

Pacific Gas and Electric Company

Illustrative Revenue Increase and Class Average Rates

Saturday, August 01, 2020

Line No.	Customer Class	Proposed Revenue Increase (000's)	Present Rates ($/kWh)	Proposed Rates ($/kWh)	Percentage Change	Line No.
	Bundled Service*					
1	Residential	$ 157,138	$ 0.22645	$ 0.23687	4.6%	1
2	Small Commercial	$ 42,031	$ 0.25928	$ 0.27037	4.3%	2
3	Medium Commercial	$ 23,820	$ 0.23122	$ 0.23824	3.0%	3
4	Large Commercial	$ 24,743	$ 0.20335	$ 0.20880	2.7%	4
5	Streetlights	$ 836	$ 0.26628	$ 0.27235	2.3%	5
6	Standby	$ 1,023	$ 0.16656	$ 0.16980	1.9%	6
7	Agriculture	$ 41,267	$ 0.22024	$ 0.22913	4.0%	7
8	Industrial	$ 17,131	$ 0.16246	$ 0.16510	1.6%	8
9	Total	$ 307,989	$ 0.21547	$ 0.22349	3.7%	9
	Direct Access and Community Choice Aggregation Service**					
10	Residential	$ 154,436	$ 0.17226	$ 0.18403	6.8%	10
11	Small Commercial	$ 49,078	$ 0.16809	$ 0.17917	6.6%	11
12	Medium Commercial	$ 38,242	$ 0.13560	$ 0.14254	5.1%	12
13	Large Commercial	$ 48,453	$ 0.10853	$ 0.11385	4.9%	13
14	Streetlights	$ 748	$ 0.17440	$ 0.18045	3.5%	14
15	Standby	$ 290	$ 0.16183	$ 0.17010	5.1%	15
16	Agriculture	$ 11,216	$ 0.15914	$ 0.17063	7.2%	16
17	Industrial	$ 24,143	$ 0.07157	$ 0.07407	3.5%	17
18	Total	$ 326,607	$ 0.13064	$ 0.13824	5.8%	18
	Departing Load***					
19	Residential	$ 0.4			1.5%	19
20	Small Commercial	$ 1.5			1.2%	20
21	Medium Commercial	$ 5.4			0.0%	21
22	Large Commercial	$ 46.1			1.9%	22
23	Streetlights	$ 0.0			0.0%	23

Notes:

* Customers who receive electric generation as well as transmission and distribution service from PG&E.

** Customers who purchase energy from non-PG&E suppliers.

*** Customers who purchase their electricity from a non-utility supplier and receive transmission and distribution service from a publicly owned utility or municipality.

A rate comparison cannot be provided for Departed Load as the applicable rates vary by specific departed load customer categories and any average rate that could be derived, would not be representative of any particular departed load category.

EXHIBIT C

Affected Governmental Entitles/
List of Cities and Counties

SERVICE OF NOTICE OF APPLICATION

In accordance with Rule 3.2(b), Applicant will mail a notice to the following, stating in general terms its proposed change in rates.

State of California

To the Attorney General and the Department of General Services.

State of California
Office of Attorney General
1300 I St Ste 1101
Sacramento, CA 95814

and

Department of General Services
Office of Buildings & Grounds
505 Van Ness Avenue, Room 2012
San Francisco, CA 94102

Counties

To the County Counsel or District Attorney and the County Clerk in the following counties:

Alameda	Mariposa	Santa Clara
Alpine	Mendocino	Santa Cruz
Amador	Merced	Shasta
Butte	Modoc	Sierra
Calaveras	Monterey	Siskiyou
Colusa	Napa	Solano
Contra Costa	Nevada	Sonoma
El Dorado	Placer	Stanislaus
Fresno	Plumas	Sutter
Glenn	Sacramento	Tehama
Humboldt	San Benito	Trinity
Kern	San Bernardino	Tulare
Kings	San Francisco	Tuolumne
Lake	San Joaquin	Yolo
Lassen	San Luis Obispo	Yuba
Madera	San Mateo	
Marin	Santa Barbara	

Municipal Corporations

To the City Attorney and the City Clerk of the following municipal corporations:

Alameda
Albany
Amador City
American Canyon
Anderson
Angels Camp
Antioch
Arcata
Arroyo Grande
Arvin
Atascadero
Atherton
Atwater
Auburn
Avenal
Bakersfield
Barstow
Belmont
Belvedere
Benicia
Berkeley
Biggs
Blue Lake
Brentwood
Brisbane
Buellton
Burlingame
Calistoga
Campbell
Capitola
Carmel
Ceres
Chico
Chowchilla
Citrus Heights
Clayton
Clearlake
Cloverdale
Clovis
Coalinga
Colfax
Colma
Colusa
Concord
Corcoran
Corning
Corte Madera
Cotati
Cupertino
Daly City
Danville
Davis
Del Rey Oakes
Dinuba
Dixon
Dos Palos
Dublin
East Palo Alto
El Cerrito
Elk Grove
Emeryville
Escalon
Eureka
Fairfax
Fairfield
Ferndale
Firebaugh
Folsom
Fort Bragg
Fortuna
Foster City
Fowler
Fremont
Fresno
Galt
Gilroy
Gonzales
Grass Valley
Greenfield
Gridley
Grover Beach
Guadalupe
Gustine
Half Moon Bay
Hanford
Hayward
Healdsburg
Hercules
Hillsborough
Hollister
Hughson
Huron
Ione
Isleton
Jackson
Kerman
King City
Kingsburg
Lafayette
Lakeport
Larkspur
Lathrop
Lemoore
Lincoln
Live Oak
Livermore
Livingston
Lodi
Lompoc
Loomis
Los Altos
Los Altos Hills
Los Banos
Los Gatos
Madera
Manteca
Maricopa
Marina
Mariposa
Martinez
Marysville
McFarland
Mendota
Menlo Park
Merced
Mill Valley

Millbrae
Milpitas
Modesto
Monte Sereno
Monterey
Moraga
Morgan Hill
Morro Bay
Mountain View
Napa
Newark
Nevada City
Newman
Novato
Oakdale
Oakland
Oakley
Orange Cove
Orinda
Orland
Oroville
Pacific Grove
Pacifica
Palo Alto
Paradise
Parlier
Paso Robles
Patterson
Petaluma
Piedmont
Pinole
Pismo Beach
Pittsburg
Placerville
Pleasant Hill
Pleasanton
Plymouth
Point Arena
Portola
Portola Valley
Rancho Cordova
Red Bluff
Redding
Redwood City
Reedley
Richmond
Ridgecrest
Rio Dell
Rio Vista
Ripon
Riverbank
Rocklin
Rohnert Park
Roseville
Ross
Sacramento
Saint Helena
Salinas
San Anselmo
San Bruno
San Carlos
San Francisco
San Joaquin
San Jose
San Juan Bautista
San Leandro
San Luis Obispo
San Mateo
San Pablo
San Rafael
San Ramon
Sand City
Sanger
Santa Clara
Santa Cruz
Santa Maria
Santa Rosa
Saratoga
Sausalito
Scotts Valley
Seaside
Sebastopol
Selma
Shafter
Shasta Lake
Soledad
Solvang
Sonoma
Sonora
South San Francisco
Stockton
Suisun City
Sunnyvale
Sutter Creek
Taft
Tehama
Tiburon
Tracy
Trinidad
Turlock
Ukiah
Union City
Vacaville
Vallejo
Victorville
Walnut Creek
Wasco
Waterford
Watsonville
West Sacramento
Wheatland
Williams
Willits
Willows
Windsor
Winters
Woodland
Woodside
Yountville
Yuba City

EXHIBIT D

Declaration of David Thomason

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Wildfire Mitigation and Catastrophic Events Interim Rates (U39E)	A.20-02-___

DECLARATION OF DAVID S. THOMASON IN SUPPORT OF THE APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) FOR WILDFIRE MITIGATION AND CATASTROPHIC EVENTS INTERIM RATES

STEVEN W. FRANK
MICHAEL R. KLOTZ

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E-Mail: steven.frank@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: February 7, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Wildfire Mitigation and Catastrophic Events Interim Rates (U39E)	A.20-02-___

DECLARATION OF DAVID S. THOMASON IN SUPPORT OF THE APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) FOR WILDFIRE MITIGATION AND CATASTROPHIC EVENTS INTERIM RATES

1. I, David S. Thomason, make this declaration to support the Application of Pacific Gas and Electric Company for Wildfire Mitigation and Catastrophic Events Interim Rates. The statements in this declaration are true and correct to the best of my knowledge.

2. I am currently the Chief Financial Officer for Pacific Gas and Electric Company (PG&E, the Company or the Utility) and Vice President and Controller for PG&E Corporation, the corporate parent of PG&E.

BACKGROUND

3. In 2008, the CPUC opened a Fire Safety Rulemaking proceeding to consider and adopt regulations to protect the public from potential fire hazards associated with overhead powerline facilities and nearby aerial communication facilities.[1/] Beginning in 2010, PG&E began incurring costs to comply with the various Fire Safety Rulemaking decisions. The costs to comply with new requirements arising from these Rulemakings were ordered to be tracked in the Fire Hazard Prevention Memorandum Account (FHPMA) for cost recovery.[2/] On December 21,

1/ CPUC Rulemaking 08-11-005. *See* also Rulemaking 15-05-006.
2/ Advice 4669-E.

2017, the CPUC issued Decision (D.) 17-12-024 adopting regulations to enhance fire-safety in high fire threat districts and on January 19, 2018 the CPUC adopted the final fire threat map. In 2018 PG&E significantly increased spending on wildfire mitigation activities including enhanced vegetation management in high fire threat districts.

4. In 2019, the CPUC-approved PG&E's 2019 Wildfire Mitigation Plan (WMP), which was submitted pursuant to Senate Bill 901.[3/] Understanding the urgent need to prevent wildfires, the effort to mitigate wildfire risk began well before the 2019 WMP was approved in May 2019. Incremental wildfire mitigation costs were captured in the Wildfire Mitigation Plan Memorandum Account (WMPMA),[4/] which covers the approved activities from PG&E's 2019 WMP, and the Fire Risk Mitigation Memorandum Account (FRMMA),[5/] which permits additional wildfire mitigation measures beyond the scope of the approved WMP for cost recovery tracking. The wildfire mitigation activities recorded to these accounts for 2019 include enhanced vegetation management, increased situational awareness and system hardening.

5. In 2019, PG&E also incurred significant costs to respond to declared catastrophic events, which included severe storms, high-wind events, and fires. These efforts included the restoration of service to customers and the repair of damaged utility facilities. PG&E likewise continued its tree mortality and fire risk reduction measures, as mandated by CPUC Resolution ESRB-4. These costs are captured in the Catastrophic Event Memorandum Account (CEMA), pursuant to Resolution E-3238 and Public Utilities Code Section 454.9, which encourages immediate emergency response work by utilities. The specific CEMA events included in this request are set forth in Table 1 below.

3/ Decision 19-05-037.

4/ Advice 5555-E, approved August 8, 2019, with an effective date of June 5, 2019 (filing date of the advice letter).

5/ Advice 5419-E, approved March 12, 2019, with an effective date of January 1, 2019.

6. On December 17, 2019, PG&E and other parties filed the Wildfire OII Settlement, which is pending CPUC approval.[6/] In this settlement, PG&E agreed to not pursue cost recovery for certain activities. See Table 2 below which illustrates certain Wildfire OII Settlement reductions relevant to this application, totaling $262.2 million. The cost breakdown by time-period (i.e., pre-2018, 2018 and 2019) is set forth in Table 3.

COSTS AND EVENTS

7. As of the first financial close[7/] for December 31, 2019, PG&E recorded $331.5 million of expense and no capital expenditures for Electric Distribution into the FHPMA. This amount is before applicable reductions related to the Wildfire OII Settlement.

8. As of the first financial close for December 31, 2019, PG&E recorded $714.8 million of expense and $585.1 million in capital expenditures incurred in 2019 for Electric Distribution into the FRMMA and the WMPMA. These amounts are before applicable reductions related to the Wildfire OII Settlement.

9. As of the first financial close for December 31, 2019, PG&E recorded $202.2 million of expense and $99.1 million in capital expenditures for Electric Distribution into the CEMA. These expense and capital amounts are broken-out by event in Table 1. These events occurred in 2019.

6/ A Joint Motion was filed by PG&E, the Safety and Enforcement Division of the California Public Utilities, Coalition of California Utility Employees, and the Office of Safety Advocate for approval of a Settlement Agreement in Order Instituting Investigation I.19-06-015.

7/ For the financial year of 2019, PG&E closed its accounting process on January 7, 2020 to prepare preliminary financial statements and review financial costs for December 2019. The amounts included in this application may vary from the final financial close, which is scheduled to be completed in mid-February 2020.

TABLE 1
RECORDED CEMA AMOUNTS BY EVENT
(THOUSANDS OF DOLLARS)

		2019 Total Spending		
Ln	**Description**	**Expense**	**Capital**	**Total**
1	Jan-Feb Storm	$109,327	$90,396	$199,722
2	Oct Wind Event	$7,731	$8,516	$16,248
3	Glencove Fire	$0	$200	$200
4	Camino Fire	$0	$10	$10
5	Tree Mortality	$85,144	$0	$85,144
6	**Total**	**$202,202**	**$99,121**	**$301,324**

10. In order to be consistent with the pending Wildfire OII Settlement, PG&E has removed from the amounts sought in this application the applicable amounts for activities which PG&E agreed to forego cost recovery. Specifically, PG&E has excluded a total of $262.2 million of expenses. This total comprises the following reductions: the FHPMA reflects a reduction of $36 million of expense related to accelerated wildfire risk reduction base camp costs and the FRMMA/WMPMA reflects a reduction of $226.2 million of expense related to Electric Distribution safety inspections and repairs. No adjustments were required for CEMA because the individual items that are excluded from recovery in the pending settlement are not included within the scope of this request. Table 2 below illustrates the exclusion of the pending Wildfire OII Settlement reductions, arriving at $1.67 billion of costs.

//

//

TABLE 2
RECORDED AMOUNTS BY PROGRAM ADJUSTED FOR PENDING WILDFIRE OII SETTLEMENT
(MILLIONS OF DOLLARS)

Line No.	Program	Total Costs Before Wildfire OII Reductions	Wildfire OII Reductions	Total Costs net of Wildfire OII Reductions
1	FHPMA	$331.5	$36.0	$295.5
2	FRMMA / WMPMA	1,299.9	226.2	1,073.8
3	CEMA	301.3	-	301.3
4	**Total**	**$1,932.7**	**$262.2**	**$1,670.6**

11. Table 3 shows the cost breakdown of the total costs, net of Wildfire OII Settlement reductions, by time-period of pre-2018, 2018 and 2019.

TABLE 3
TOTAL RECORDED AMOUNTS BY PROGRAM AND YEAR, NET OF PENDING WILDFIRE OII SETTLEMENT REDUCTIONS
(THOUSANDS OF DOLLARS)

Line		Prior to 2018		2018		2019		Total Spending
No.	Program	Expense	Capital	Expense	Capital	Expense	Capital	Total
1	FHPMA	$793	$0	$272,224	$0	$22,447	$0	$295,464
2	FRMMA / WMPMA	-	-	-	-	488,644	585,142	1,073,786
3	CEMA	-	-	-	-	202,202	99,122	301,324
4	**Total**	**$793**	**$0**	**$272,224**	**$0**	**$713,293**	**$684,264**	**$1,670,574**

12. In addition to the removal of costs related to the pending Wildfire OII Settlement, this request also excludes costs related to: (1) the 2015 Butte Fire, (2) the 2017 October North

Bay Fires, (3) the 2018 Camp Fire, (4) the 2019 Kincade Fire, (5) the Bethel Island Fire, and (6) the 2019 Public Safety Power Shut-Off Events, as well as costs already submitted in other proceedings such as the 2018 CEMA (A.18-03-015)[8/] and the 2019 CEMA (A.19-09-012).[9/]

13. As shown in Table 3, the total unrecovered costs being reflected in this application is $1.67 billion, which translates into a revenue requirement of $1,057.6 million as shown in Table 4.

TABLE 4
RECORDED AMOUNTS BY PROGRAM CONVERTED TO REVENUE REQUIREMENT
(THOUSANDS OF DOLLARS)

Line No.	Program	Expense	Capital	Total	Associated Revenue Requirement
1	FHPMA	295,464	-	295,464	317,441
2	FRMMA / WMPMA	488,644	585,142	1,073,786	505,250
3	CEMA	202,202	99,122	301,324	234,871
4	**Total**	**$ 986,310**	**$ 684,264**	**$ 1,670,574**	**$ 1,057,561**

14. Based on historical experience related to PG&E's previous CEMA filings, this application requests interim relief for 85 percent of the revenue requirement associated with the applicable costs, which is calculated to be $898.9 million. This calculation is shown in Table 5.

8/ The 2018 CEMA (A.18-03-015) included 10 events spanning from 2016 through 2018. On January 24, 2020, PG&E requested authority to submit the tree mortality costs that are shown in Table 1, line 5, in its 2018 CEMA case in the April 2020 timeframe. That request is pending.

9/ The 2019 CEMA (A.19-09-012) included 13 events spanning from 2017 through 2018. PG&E intends to seek similar interim rate relief to that sought here for costs in the 2019 CEMA case.

TABLE 5
CALCULATION OF 85 PERCENT OF THE ASSOCIATED REVENUE REQUIREMENT
(THOUSANDS OF DOLLARS)

Line No.	Program	Total Associated Revenue Requirement	85% of Associated Revenue Requirement
1	FHPMA	317,441	269,825
2	FRMMA/WMPMA	505,250	429,462
3	CEMA	234,871	199,640
5	Total	$ 1,057,561	$898,927

PROCESS CONTROLS

15. PG&E takes appropriate steps to record the applicable costs to the FHPMA, FRMMA/WMPMA and CEMA accounts, consistent with the regulatory decisions creating these memorandum accounts and the approved preliminary statements.

16. PG&E establishes dedicated work orders in PG&E's financial accounting system, SAP, to properly track and record all relevant expense and capital expenditures. Each work order is assigned to a responsible cost center in SAP in order to ensure cost ownership and transparency.

17. PG&E's finance organization and operational lines of business establish controls to ensure costs are booked to the correct work orders. These controls include detailed cost accounting instructions to the appropriate lines of business and analysis of recorded costs in comparison to budget through monthly spending reports. When spend is identified that does not belong in a certain program it is adjusted out of the account. The procedures and cost monitoring activities are designed to ensure that costs associated with specific activities are not mingled with the work that is funded by the General Rate Case or other regulatory proceedings.

18. As part of the financial closing process, a monthly review of the expenditures is performed by PG&E's respective departments, including program managers and the finance organization. This monthly review, as well as account reconciliations and Sarbanes-Oxley controls testing, are conducted to ensure the appropriateness of the charges to a given work order.

19. Prior to formal filing of an application for cost reasonableness, PG&E further scrutinizes and adjusts the costs recorded in the memorandum accounts. This scrutiny looks for any costs improperly booked to these accounts and adjusts the request to take account of any Commission decisions or other accounting orders. As an example of the type of adjustment made prior to formal filing, PG&E removes capitalized administrative and general (A&G) costs and benefits-related expense from the CEMA, pursuant to D.08-01-021. These adjustments typically comprise approximately 5% of otherwise-eligible recorded costs.[10/]

20. PG&E's proposed 15 percent reduction from the revenue requirement associated with PG&E's otherwise-eligible recorded costs is thus expected to substantially exceed the typical level of adjustments to otherwise-eligible recorded costs. The proposed reduction is also consistent with historical cost recovery percentages for its past CEMA filings.

FINANCIAL CIRCUMSTANCES

21. PG&E's interim rate relief request is expected to enable PG&E to obtain a lower interest rate from the marketplace on debt. A lower interest rate would create an immediate benefit to customers that would last for decades into the future.

22. Aside from broader economic conditions and market forces, there are two major factors that impact interest rates paid by utilities.

10/ This percentage was determined based on analysis of PG&E's past CEMA cases from the 2009 CEMA through the most recently filed case, the 2019 CEMA.

23. The first major factor is the perception that credit rating agencies and investors have of regulatory risk in California. One of the most-cited factors in assessing regulatory risk is the regulator's track record for providing timely cost recovery. The credit rating agencies' assessment of PG&E's ability to obtain timely cost recovery directly impacts their overall assessment of the Company's business risk. The approval of this request for interim relief would be a favorable factor in the credit rating agencies' view of the regulatory framework and PG&E's business risk.

24. The credit rating agencies heavily weight timely cost recovery when evaluating credit ratings. For example, regulatory risk comprises 50% of the Moody's rating. Similarly, in Fitch Rating's Utility Sector Credit Factors, Fitch states, "Tariff setting mechanisms that allow utilities to recover costs in a manner that limits regulatory lag are favorable to their risk profile."[11/] And S&P Global's regulatory utility methodology also emphasizes the importance of <u>timely cost recovery</u> and <u>strong regulatory environment</u> for regulated utility credit ratings:

> The regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance. **We base our assessment of the regulatory framework's relative credit supportiveness on our view of how regulatory stability, efficiency of tariff setting procedures, financial stability, and regulatory independence protect a utility's credit quality and its ability to recover its costs and earn a timely return.** Our view of these four pillars is the foundation of a utility's regulatory support. We then assess the utility's business strategy, in particular its regulatory strategy and its ability to manage the tariff-setting process, to arrive at a final regulatory advantage assessment.[12/]

Currently, S&P highlights a Key Strength for PG&E: "The company minimizes regulatory lag by using forward-looking test years, decoupling, and multiyear rate setting."[13/]

11/ Fitch Ratings, "Rating U.S. Utilities, Power and Gas Companies," March 11, 2014.

12/ S&P Global Ratings, "Key Credit Factors For The Regulated Utilities Industry," November 19, 2013 (emphasis added).

13/ S&P Global Ratings, "Summary: Pacific Gas & Electric Co.," November 9, 2018.

However, multi-year delays in cost recovery of the order of magnitude previously described threaten to change that perception.

25. The improved customer benefits associated with a perception of regulatory risk would be realized in PG&E's next cost of capital proceeding, when such improvements would translate to reductions in the otherwise-applicable cost of capital.

26. The second major factor impacting interest rates paid by utilities is a utility's ability to service its debt, i.e., the amount of ongoing cash flow available for that purpose. Approval of this request would have a material impact on that cash flow as well as the level of debt needed to finance the costs. The most important financial indicator used by the credit rating agencies to assess a firm's ability to make timely payments of principal and interest (aka "debt service") is the ratio of its funds from operations (FFO) cash flow to total debt (FFO/Debt). This metric measures the annual cash flow available to service the amount of total debt outstanding. FFO is basically the utility's cash revenues less the utility's cash expenses (excluding capital expenditures). To the extent PG&E is financing capital projects or operating expenses with debt, but not recovering any of those costs, FFO will decrease, while debt will increase. That means there is not only a higher level of debt, but a lower level of cash flow is available to pay interest or principal on that debt.

27. The amount at issue here—$1.67 billion recorded to the previously mentioned memorandum accounts—is large enough to have a negative impact on PG&E's cash flows and credit ratings, which affect PG&E's borrowing costs and customer rates. Without timely rate recovery for these costs, PG&E's annual cash flow (FFO) is about $47 million lower due to higher interest expense to finance the delayed recovery. Debt is increased by $1.3 billion, based on the expense portion of the $1.67 billion and the debt-financed portion of the capital

component, since the $684 million[14/] capital component is financed with 52% equity.[15/] Using PG&E's 2017 pre-bankruptcy financial data[16/] as a basis to illustrate the impact on its FFO/Debt ratio, and assuming PG&E's current, adopted cost of capital for financing the approximate $684 million of capital deferred for future recovery, PG&E has calculated the impacts of the interim relief on the FFO/Debt ratio, shown in Columns A and B of Table 6. The data show that the magnitude of the impact on PG&E's FFO/Debt ratio is a decrease on the order of 1 percent (19.7%-18.5%).[17/]

TABLE 6
IMPACT ON PG&E FINANCIAL METRICS
(DOLLARS IN MILLIONS)

		A	B
Line No.		**Without Accelerated Cost Recovery**	**With Accelerated Cost Recovery**
1	FFO	$4,801	$4,905
2	Debt	$25,885	$24,898
3	FFO/Debt	18.5%	19.7%

28. Although this 1% change may seem small relative to the FFO/Debt ratio, small, sustained changes in the ratio can result in credit rating changes when the rating agencies view such changes as a shift in the company's cash flows and a trend to increased debt leverage due to

14/ See Table 3.

15/ This cash shortfall in turn requires PG&E to raise an additional $47 million of debt to pay interest, further worsening its FFO/Debt ratio.

16/ The underlying credit metric data are from Standard & Poor's (S&P) data base reflecting S&P actual amounts for 2017 and were included in PG&E's opening comments in the CPUC's Wildfire Cost Recovery Criteria OIR – R.19-01-006. The figures in Table 6 will change once PG&E completes the recapitalization as proposed in its January 31, 2020 testimony filed in OII 19-09-016.

17/ These figures assume PG&E finances 47.5 percent of $0.7 billion of capital expenditures with debt at a weighted cost of 5.16 percent, and finances about $1 billion of operating expense with short-term debt at an annual cost of 3.04%. The incremental cash flow in column B reflects the increase in FFO from net income and depreciation.

regulatory lag.[18/] A decrease in this ratio on the order of 1%, combined with a more skeptical view of the regulatory environment, could lead to a change in the credit rating itself, and hence could have an impact on PG&E's borrowing costs.

CUSTOMER FINANCIAL BENEFITS

29. The customer benefit from interim relief comes in two main forms: the direct interest costs and the indirect credit metric impact.

30. The direct interest is the interest needed to finance the debt for the balances between the time PG&E incurs the costs and the time the costs are put into rates. This cost can be calculated by multiplying the total debt needed to finance the costs by the authorized balancing account interest rate recoverable from customers. In a simple example, the expenses above, both capital and expense, are carried in full through 2022 and then are recovered from customers in two years, 2023 and 2024. Over this five-year period, 2019 through 2024, interest costs would be put into rates and would amount to approximately $67 million using an estimated authorized interest rate of approximately 1.6% on the average annual balances.[19/]

31. The indirect customer benefits are the costs associated with a perception of regulatory risk and impacted financial metrics. Generally, investors expect that utility expenses, such as for maintenance and operating costs and purchased power (i.e., for expenditures that do not create an asset that provides service for more than 12 months) are currently recoverable in rates on a forecast basis. Similarly, there is an expectation for capital projects (those that benefit

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18/ For example, see S&P Global Ratings - Sempra Energy, July 9, 2019, p. 4: "We could also lower the rating if FFO to debt is consistently lower than 13%". See also S&P Global Ratings – Edison International, July 15, 2019, p. 2: "Our ratings on Edison could stabilize if it participates in the insurance fund, is able to effectively finance its contribution to the insurance fund such that FFO to debt is consistently above 15%". And see S&P Global Ratings – PG&E Corp., May 12, 2019 p. 4: "Additionally, we could also lower the [credit] rating if FFO to debt consistently weakens to below 17%."

19/ This interest rate is calculated using the historical four-year average of the three-month commercial paper rate from 2016 through 2019.

both current and future customers) that the expenditures will be recoverable through a revenue requirement that includes both a capital recovery component (depreciation) and a rate of return. When deviating materially from this generally expected ratemaking process, investors impute more risk to the regulatory framework.[20/]

32. The difference in cost to customers of a credit rating that is at the bottom of the investment grade category (BBB-) and one below it (BB+) is substantial – about 0.32%.[21/] Applied to PG&E's portion of rate base financed by debt, the additional annual cost to ratepayers would be on the order of $60 million, or about $1.8 billion over 30 years.[22/] Even moving from a BBB+ to a BBB credit rating (one "notch") would increase customer costs by about $25 million annually.[23/]

33. The indirect customer benefits associated with a perception of regulatory risk and impacted credit metrics would be realized in PG&E's next cost of capital proceeding, when such improvements would translate to reductions in the otherwise-applicable cost of capital. From a ratemaking perspective, PG&E intends to file an update to its cost of debt upon emergence from bankruptcy.[24/] To the extent this interim relief lowers PG&E's cost of debt, customers would benefit in the short term by an adjustment lowering PG&E's cost of capital.

20/ Deferring cost recovery is also unfair to customers, since it gives current customers a free ride at the expense of future customers and fails to signal to customers the actual costs of providing utility service to them.

21/ The figure of 0.32% is estimated by taking 13 months of observed market returns on BBB and BB yields, taking the 1- month average, and dividing by 6 notches to estimate the difference in interest rate between a BBB- and BB+ credit rating.

22/ Assuming a total rate base of about $40 billion, and a 47.5% debt ratio.

23/ This estimate is based on observed yields of A and BBB utility bonds over 12 months, and taking the simple average and dividing by 3 "notches" to estimate the impact of a single notch movement from BBB+ to BBB, 0.14%.

24/ In A.19-04-015, PG&E "propose[d] to update its cost of debt for cost of capital purposes, for the period beginning after it emerges from bankruptcy to incorporate the costs of its exit financing, and the appropriate forward-looking forecast of debt costs for the remaining forecast period." See D.19-12-056, mimeo, pp. 13-14. It is PG&E's intent to file an advice letter within 30 days of the effective date of the

OTHER CUSTOMER BENEFITS

34. PG&E's suppliers are also adversely impacted by PG&E's declining financial health. For example, Topaz Solar Farms LLC, and Panoche Energy were downgraded to junk status by each of the major rating agencies in 2019 as a result of PG&E's declining credit quality. These credit actions reflect PG&E's role as a key revenue counterparty for these projects and have the potential to further increase costs for our customers.

35. The correlation between PG&E's financial condition and cost to customers is indisputable. The potential for higher costs to customers resulting from the lack of timely cost recovery is substantial and could be on the order of hundreds of millions of dollars in future years. As such, PG&E and the CPUC should collectively be looking for any reasonable action that can be taken to both improve credit ratings and reduce the cost of capital for our customers

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed on February 7, 2020, at San Francisco, California

David Thomason

David S. Thomason

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implementation of PG&E's plan of reorganization to implement the lower cost of debt resulting from that plan.